Section 1: Past and Present Trends in Washington's Natural Gas Market

Introduction

This report updates the 2001 natural gas study, *Convergence: Natural Gas and Electricity in Washington,* to reflect current market conditions, identifies important natural gas supply and market issues, and considers the implications for consumers and energy policy in Washington State.

Background

The Pacific Northwest is served by two major natural gas pipelines (Figure 1.1). The Northwest Pipeline, owned and operated by the Williams Company, was constructed in the late 1950s and reaches most urban locations in the state. The Pacific Gas & Electric Gas Transmission Northwest (PG&E GTN) pipeline (frequently referred to as "PGT," after the previous name, "Pacific Gas Transmission") went into service in 1961 primarily to serve customers in California, but now also serves as an important source of supply for the region.

The Northwest Pipeline connects the Pacific Northwest to natural gas fields in the Rocky Mountains region and in British Columbia and Alberta, Canada. The Northwest Pipeline interconnects with the facilities of both Westcoast Energy, Inc. and Sumas International Pipeline, Inc. at the Canadian border near Sumas, Washington, and it connects with El Paso Natural Gas Company, Transwestern Pipeline Company, Colorado Interstate Gas Company, Questar Pipeline Company, Kern River Gas Transmission Company, and Paiute Pipeline Company at various points in New Mexico, Colorado, Wyoming and Nevada.

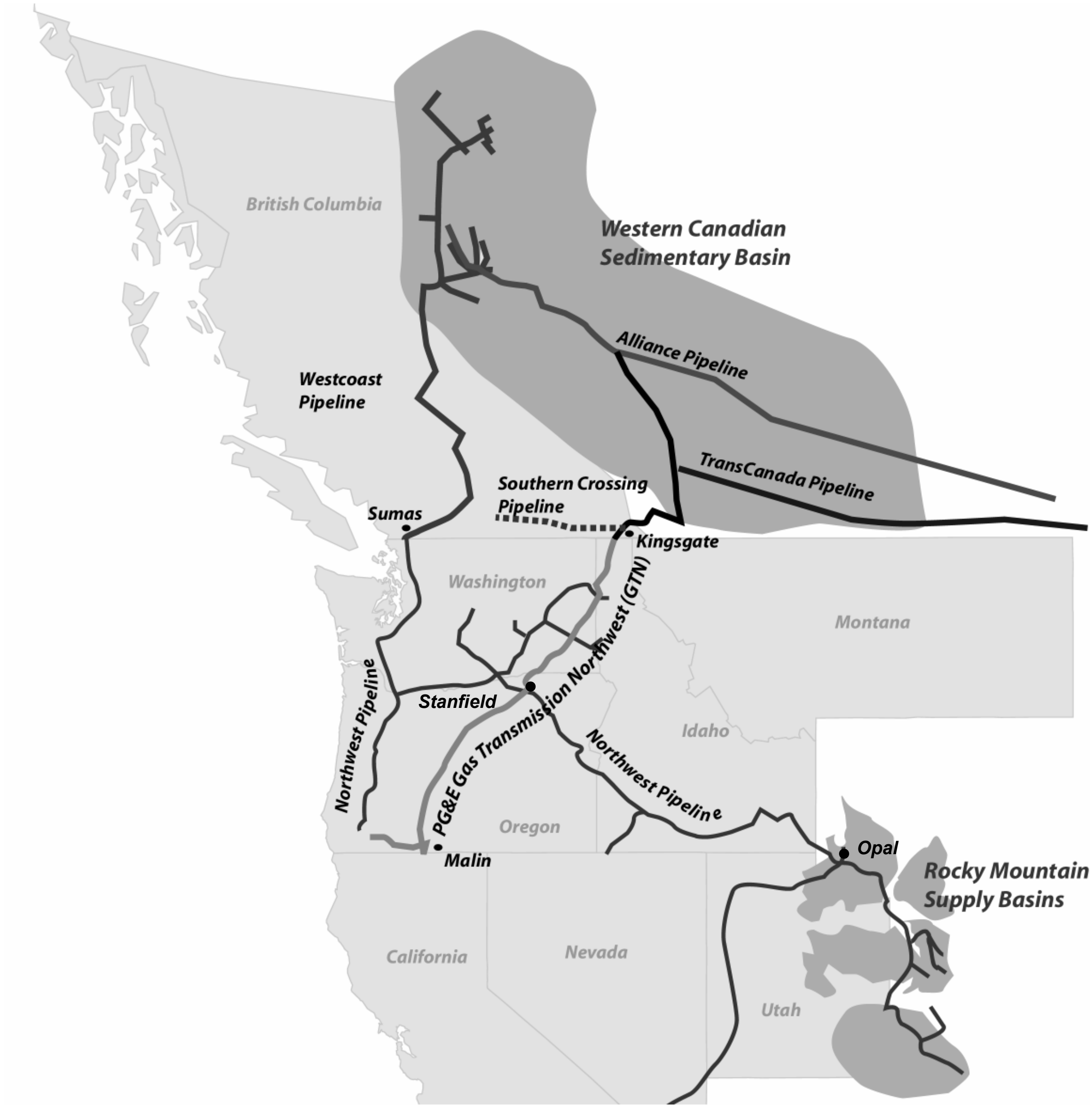

Figure 1.1. Major Natural Gas Pipelines Serving the Northwest

The GTN pipeline was constructed primarily to connect California to natural gas supplies in Alberta, Canada. But it also serves customers in the Pacific Northwest (Avista Utilities and Cascade Natural Gas) and connects to the Northwest Pipeline at Stanfield, Oregon, and Spokane and Palouse, Washington. The GTN pipeline interconnects with TransCanada at Kingsgate, British Columbia, and Pacific Gas and Electric Company and Tuscarora Gas Transmission Company at Malin, Oregon. GTN also delivers to power plants at Coyote Springs and Hermiston, Oregon.

In addition to flowing gas from pipelines, Washington State's gas utilities rely on underground storage fields to meet peak demands. The location of major storage facilities close to end-use customers allows storage to substitute for pipeline capacity in meeting peak demand days. The largest, Jackson Prairie near Chehalis, Washington, with18,300 MDth[1] working gas capacity, is owned by Avista Corporation, Puget Sound Energy and Northwest Pipeline in equal shares. The Mist, Oregon, storage facility is owned by Northwest Natural. In addition, Questar has a storage facility at Clay Basin in Northeast Utah in which Puget Sound Energy, Northwest Pipeline and other regional shippers hold capacity. These facilities are primarily used for seasonal storage to increase peak day deliverability. Gas is injected during off-peak periods and retrieved during the peak winter heating season. Refill begins in spring and continues through September, when 90-100 percent of capacity is usually achieved. As much as half of the gas consumed on a cold winter day comes from storage fields.

Within local communities, gas is distributed by four investor-owned utilities (Puget Sound Energy, Avista, Cascade Natural Gas and Northwest Natural Gas), sometimes called local distribution companies (LDCs), and three small city-owned utilities (Ellensburg, Enumclaw and Buckley). This contrasts with electric utility customers where just under half are served by regulated investor-owned utilities and the remainder by public utilities. The gas utilities purchase gas at market hubs,[2] and transport the gas through the interstate pipeline system to the "city gate" where it enters the local distribution system. The Washington Utilities and Transportation Commission (UTC) regulates local distribution company gas retail rates. Service territories of the four major LDCs within Washington State are depicted in Figure 1.2. Many large customers arrange for their own gas supplies from market hubs and purchase transportation services from interstate pipelines and/or LDCs.

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[1] Thousand decatherms (MDth). A decatherm is equal to a million British Thermal Units (Btu).

[2] Natural gas market hubs evolved from Federal Energy Regulatory Commission (FERC) gas industry restructuring orders in 1992. These market centers provide new gas shippers with many of the physical capabilities and administrative support services formerly handled by interstate pipeline companies "bundled" sales and services. Centers exist where two or more pipelines interconnect. The Sumas Center in British Columbia is the principal source for trading and transportation of natural gas in the Pacific Northwest. Other centers relevant to the region are at Kingsgate, Idaho; Malin and Stanfield, Oregon and the Opal Hub in Wyoming.

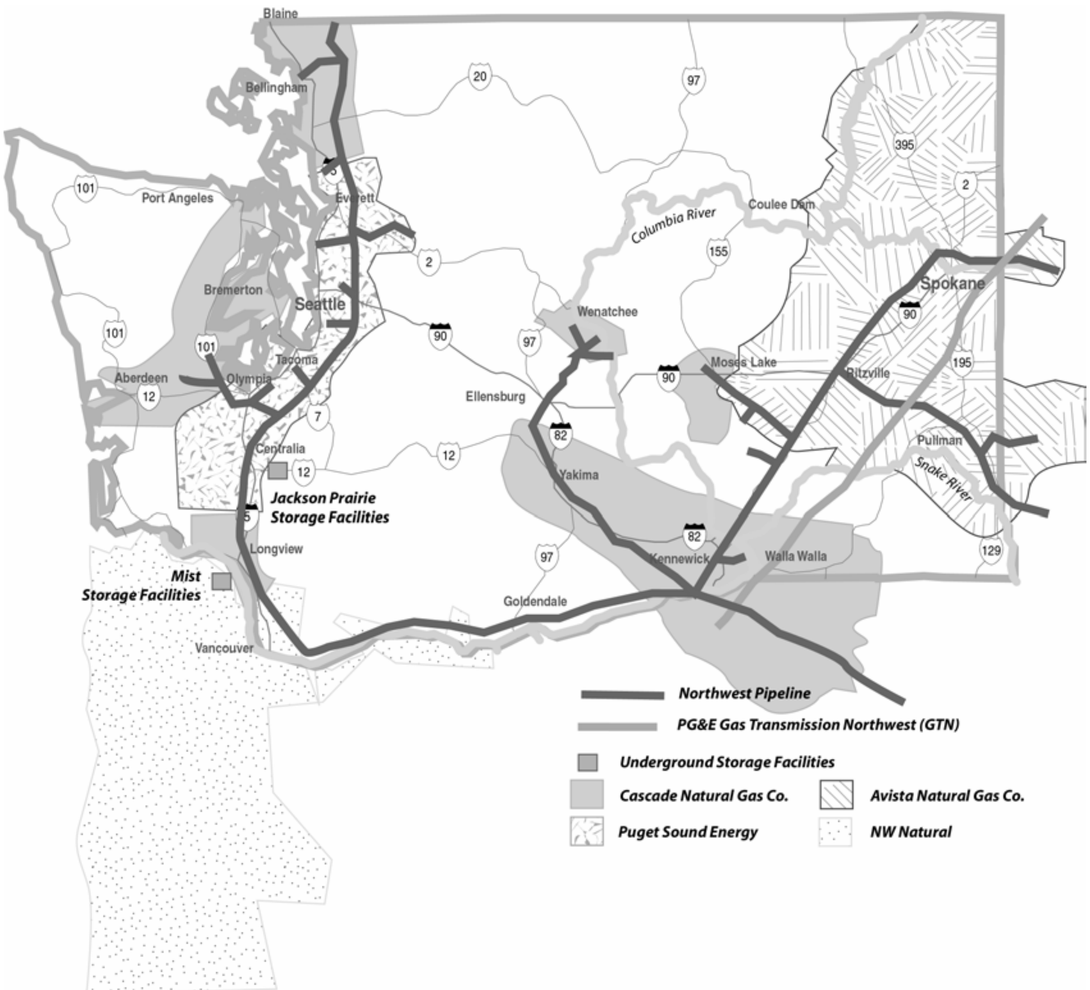

Figure 1.2. Natural Gas Utility Service Areas in Washington State

Past Trends and the Energy Crisis

The period leading up to the energy crisis of 2000 and 2001 can be characterized by a period of regulation prior to 1985, followed by a period of deregulation and industry restructuring.

Pre-1985: Regulation

During this period, the Federal Power Commission, now the Federal Energy Regulatory Commission (FERC), regulated the price of natural gas from the well to the pipeline, and the price charged by pipelines to deliver the gas to local gas utilities. State regulatory commissions regulated local gas utilities' prices to retail customers. Gas prices were regulated from the point of production to the point of use. Because prices were low, natural gas demand grew significantly until the early 1970s. A large share of natural gas production remained a by-product of oil well development, where profits were not regulated. But low prices and a maturing resource base meant that an insufficient number of new wells were being developed. By the early 1970s domestic gas supplies could not keep pace with growing demand.

This fact was very important to the evolution of the natural gas market in the state of Washington. The U.S. producers were subject to federal price controls, while the Canadian producers were not. As domestic supplies became limited and did not meet demand, Washington utilities turned to Canadian suppliers.

This had several impacts on the Northwest. First, the pipeline capacity from the Southwest was not expanded, since there was no additional marketable domestic gas available. Second, pipeline capacity to the Canadian border was expanded. As a result of having much of our demand met with un-regulated higher-cost Canadian gas, consumers in Washington State paid gas prices that were higher (more than $1/MMBtu in the early 1980s) than were paid in other parts of the United States. Higher than average gas prices, coupled with the lowest electric rates in the nation, meant that natural gas was slow to evolve as a residential and commercial heating fuel in the Pacific Northwest.

The Federal Power Commission began raising the regulated price of wellhead gas in the mid 1970s to provide incentive to bring production on line. Higher price limits and the shortages during 1972-77 caused some increase in drilling and stabilized productive capacity. Higher fuel prices combined with the recessions of the 1970s, and other factors, reduced demand for natural gas. The Natural Gas Policy Act (NGPA) of 1978 began the deregulation process. The newly authorized FERC allowed several more price increases during 1978-85 for regulated gas, which now also included intrastate gas. Gas wells that came into production after the NGPA of 1978 were not regulated, so the market was becoming a mixed regulated and open market. In addition, the high wellhead prices allowed by FERC were no longer constraining resource development. The deep recession of 1980-82 and high oil and gas prices resulted in demand destruction, and efficiency improvements. The outcome was that as supply was increasing, demand was falling rapidly, resulting in a drop in natural gas and oil prices in the mid 1980s.

It also should be noted that the Federal Power Plant and Industrial Fuel Use Act, passed by Congress in 1978, prohibited natural gas use in new electric utility generating facilities starting in 1980, except under specific exemptions such as peaking power plants. The intent of this prohibition was to conserve natural gas for uses other than the generation of electricity, encourage the use of coal or alternative fuels in the place of natural gas, and ensure natural gas availability for high priority purposes. The utility industry strongly opposed this provision because of the high cost of replacing natural gas generation. In 1981, when gas shortages disappeared and gas supplies increased, Congress repealed this prohibition as part of the Omnibus Budget Reconciliation Act Of 1981.

1985-1999: Natural Gas Industry Restructuring

During the 1980s, federal and state regulatory authorities significantly restructured the natural gas industry regulatory framework and decontrolled domestic gas prices in 1985. The federal action was directed at stimulating exploration and drilling, introducing additional competition into the industry, and increasing the utilization of the gas pipeline network. State action was largely a response to federal action.

A key change enacted by FERC was unbundling of pipeline service, separating the business of gas supply from the business of operating the pipeline. With the new structure, each of the local distribution companies in Washington State entered into direct contracts with gas producers and/or marketers for their gas supply and they purchased capacity from the pipeline companies to deliver the natural gas. Also industrial customers were allowed to become "transportation" customers, meaning they could buy directly from producers and pay the utility only for delivery services.

These changes in the market along with reductions in the cost to bring new supplies on line (due to improvements in seismology and drilling technology) led to increased supply, lower prices, and growth in demand.

Historical Natural Gas Prices and Demand

After peaking in the early 1980s, inflation adjusted retail natural gas prices had declined significantly by 1990, nearing price levels of the mid-1970s (Figure 1.3). Prices were relatively stable throughout the 1990s. Residential prices were highest and were almost twice as much as industrial rates for much of this period, largely due to the higher cost of delivering gas to smaller customers. Natural gas prices for utilities tended to be more volatile because consumption was primarily for natural gas-fired power plants used for meeting peak power demand, and was generally supplied under interruptible rate schedules. Thus consumption for electricity generation was modest (1 to 5 percent of total) and varied from year-to-year.

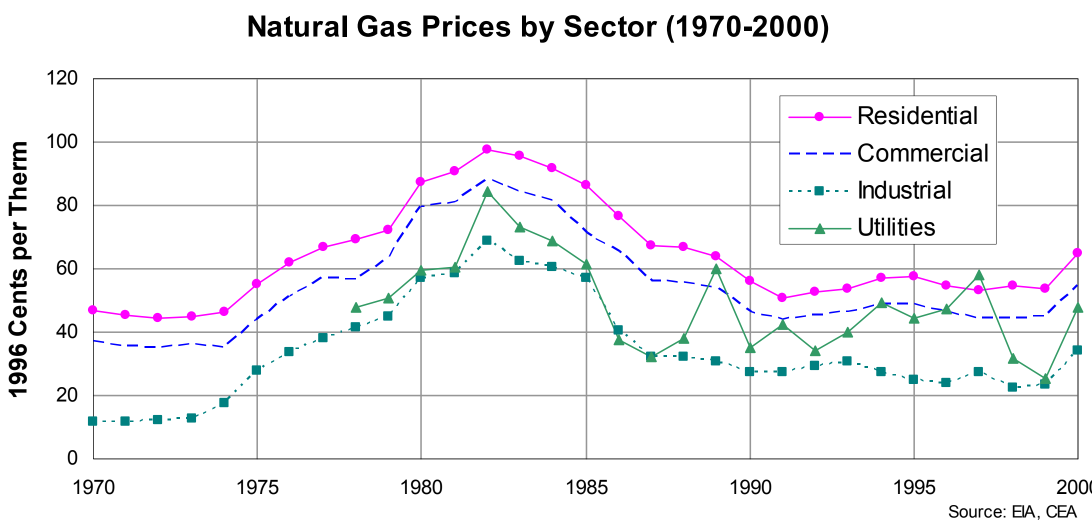

Figure 1.3. Historical Natural Gas Prices in Washington State

Natural gas consumption in Washington State grew through the early 1970s, declined through the early 1980s, and resumed its growth through most of the 1980s and 1990s (Figure 1.4). These trends reflect the supply and price situation during these periods. Total statewide natural gas consumption in 1999 was about a third more than the previous consumption peak in 1973.

Residential and commercial consumption was relatively stable through much of this period, showing modest declines in the late 1970s and growth in the 1990s. Increasing demand in these sectors was due to growth in the population and the economy as well as an increasing preference for natural gas for heating, water heating and industrial processes. This was partly due to higher electricity prices and lower natural gas prices improving the relative advantage of natural gas as a heating fuel. Together, the residential and commercial sector accounted for a little less than 50 percent of natural gas consumption in Washington State in 1999. Along with small industrial customers, these are the core market sectors for natural gas distribution utilities.

Industrial natural gas consumption tends to be more volatile and price sensitive than the residential and commercial sectors. During the 1980s natural gas consumption was less than half the amount in 1973 and did not return to the 1973 peak until 1998. Industries use natural gas primarily for process heat and, in some cases, as a direct input to manufacturing of substances such as plastics and fertilizer. When natural gas supplies were unreliable and prices high from the mid 1970s to the early 1980s, industries used other fuels for process heat or they cut back production. During this period there was growth in the consumption of biofuels, but overall energy use in the industrial sector dropped 10 to 15 percent.

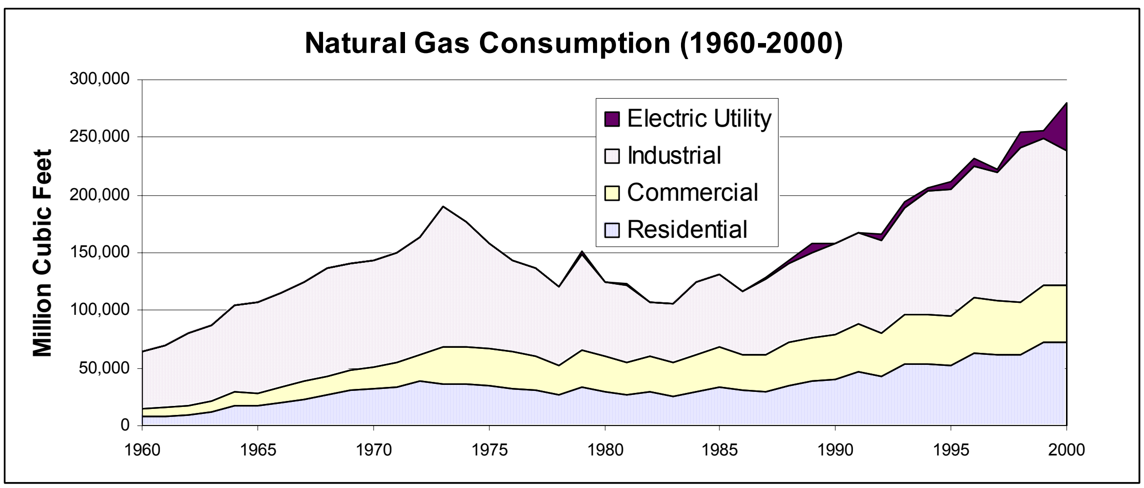

Figure 1.4. Historical Natural Gas Consumption in Washington State Source EIA

In the Pacific Northwest, the consumption of natural gas for electricity generation historically has been for utility-owned natural gas-fired peaking generators. These plants were designed to be used a limited number of days per year to meet peak system demands. Use of these plants was limited during the 1980s and early 1990s and consumption of natural gas in the utility sector was low.

But this situation began to change during the 1990s. New gas-fired cogeneration facilities[3] went on line at a half-dozen industrial sites in Washington State and these were

[3] These cogeneration plants were installed at oil refineries and wood products facilities. Cogeneration plants generate electricity and the waste heat from electricity generation is used as process heat by the host

followed by a number of gas-fired power plants. New combined cycle combustion turbine technology (CCCT)[4] coupled with extremely low commodity gas prices made natural gas the nearly universal fuel of choice for electricity generation. Gas plants were relatively inexpensive to construct and operate,[5] and environmentally were much preferred to coal or nuclear plants. In contrast to peaking generators, these new plants were intended to run most of the time and they rely on natural gas as their only fuel, although some of the cogeneration plants built in the 1980s and 1990s can also use other fuels such as wood waste, refinery gas, or spent pulping liquors. As these natural gas power plants began to come on line, new demands were placed on the natural gas system.

It is important to note that natural gas consumption for power plants owned by industries or independent power producers is included as part of industrial sector energy consumption in the historical data shown in Figure 1.4.[6] From 1991 to 1995, six new cogeneration plants went into operation at industrial sites in Washington State. The Energy Information Administration (EIA) recently estimated that about 25 to 30 billion cubic feet (Bcf)/year of industrial natural gas use during the 1997 to 2000 period was for electricity generation. Thus the consumption of natural gas for electricity generation grew from minimal amounts in 1990 to over 70 Bcf in 2000, which is about a quarter of total natural gas consumption in Washington State.

2000-2001: The West Coast Energy Crisis

The West Coast energy crisis that began in mid-2000 and ran through most of 2001 caught government, utilities, businesses and consumers by surprise. The events of this period represent a substantial departure from past expectations of natural gas and electricity markets. We briefly review the situation here. For a more complete discussion see Karier 2001 and CEC 2001.

Adequate energy supplies and relatively low energy prices in the 1990s set the stage for the energy crisis. Wholesale gas prices dropped as low as \$1/MMBtu, and wholesale electricity prices ranged between \$10 and \$20/Megawatt-hour (MWh)[7] through 1997. Depressed gas prices led to limited gas exploration in the U.S. Rocky Mountain areas,

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industry. This can increase the overall plant efficiency because a larger portion of the energy input is used.

[4] Combined cycle combustion turbines utilize the waste heat from the first stage of electricity generation in a second stage, thus boosting power plant efficiency.

[5] The Fourth Northwest Conservation and Power Plan (Northwest Power Planning Council 1998) estimated levelized electricity costs (includes amortized capital costs and fuel and operating costs) for a new combined cycle natural gas generating plant to range from 2.7 to 3.2 cents per kilowatt-hour (kWh). This was the least expensive generating resource with the exception of low-cost hydro. For comparison, coal plants had a levelized cost of 3.7 to 4.2 cents/kWh, wind was 3.6 to 7.5 cents/kWh, and nuclear was 4.3 cents/kWh.

[6] Recently, the Energy Information Administration has updated the accounting methodology for the electric power sector, such that it includes utilities, independent power producers, and others whose primary business is to generate electricity.

[7] A Mega-watt hour (MWh) is equal to 1000 kWh or 10^6 watt-hours.

and slower growth in gas drilling in Canada. Low electricity prices and uncertainty in electricity markets resulted in little new power plant construction in the Northwest.

Yet demand for electricity and natural gas continued to grow throughout the 1990s as a result of population growth in the region and a strong economy. But the impact of this growth on energy supply was masked by mild weather and favorable hydroelectric conditions. Cool summers and warm winters moderated the demand for electricity (and natural gas-fired generation) in the summer and natural gas space heating in the winter. A surplus of low-cost hydroelectricity reduced the natural gas demand from natural gas power plants, particularly in California.[8]

This all changed in 2000 and 2001 when a confluence of events increased energy demand, constrained supply, and contributed to extreme market volatility.

- Colder than normal winter temperatures across the country in the winter of 2000-01 put additional demands on an already strained natural gas system. Natural gas prices increased sharply nationwide to $8-10/MMBtu.

- Drier conditions in the Pacific Northwest and the West Coast in 2000 and a drought in 2001 resulted in substantial reductions in hydroelectricity capacity. Annual hydroelectric production on the Federal Power System in 2001 was 45 percent less than production in 1997 and 40 percent less than 1999: a 4,000-5,000 average Megawatt (aMW) deficit.[9] This mirrored the situation in the Western Electricity Coordinating Council (WECC), where hydroelectric generation was also 40 percent less: a 10,400 aMW deficit in 2001 relative to 1999. Natural gas-fired generation picked up the largest share of this decline in the Western States region (Table 1.1). This was a primary contributor to the energy crisis.

Table 1.1. Electricity Generation by Major Fuel Type, WECC

	Generation by Fuel Type, January to December (GWh)[10]			
	2001	2000	1999	Difference 1999 to 2001
Coal	231,621	234,501	226,987	2%
Nuclear	70,194	74,162	69,874	.5%
Hydroelectric	135,987	193,561	227,419	**-40.2%**
Natural Gas	174,361	158,193	126,457	**37.9%**
Other	30,179	26,909	29,063	3.8%
Total Generation	*642,342*	*687,326*	*679,800*	*-5.5%*

[8] Hydropower production on the Federal Power System was generally about 10 percent above normal from 1996 through 1999.

[9] An average megawatt (aMW) is equal to one megawatt of production/consumption over a one year time period, or 8,760 Megawatt-hours.

[10] A Giga-watt hour (GWH) is equal to 10^9 watt-hours.

- North American natural gas production capacity continued to fall thru the 1990s[11] and natural gas put into storage during the April to October storage period was about 10 percent below normal, reducing available supply for the following winter. This made for a very tight balance between supply and demand.

- The structure of California's deregulated electricity market contributed to price volatility in electricity and natural gas markets. Electric utilities in California had to divest their generation resources and purchase the vast majority of their power on hourly markets, thus limiting their ability to control market risk. Some companies engaged in questionable trading practices and withheld supplies in an attempt to raise market prices. Extremely high margins in electricity markets created upward pressure on natural gas prices.

- There is also evidence that some companies reported false information to publishers of natural gas price indices in order to affect favorable movements of published prices. FERC is currently investigating these concerns to ensure that prices are transparent and the market functions properly, and a number of federal criminal probes are under way.

- An explosion on the El Paso natural gas pipeline in New Mexico took a significant amount of transmission capacity to California out of service. El Paso was also alleged to have intentionally withheld pipeline capacity during 2000 and 2001, and recently agreed to pay parties in California billions of dollars to settle claims against the company: Washington and Oregon also received settlement money. Pipeline capacity constraints during the winter of 2000-2001 pushed up prices for delivery points on the West Coast. For example, during December 2000 price differentials between producing areas in the Rocky Mountains and Alberta, Canada, and delivery points in California and the Northwest grew to $10-20/MMBtu. These price differentials tended to be more pronounced and longer lasting for delivery points in California.

The energy crisis produced a dramatic increase in wholesale prices for natural gas. Figure 1.5 shows average monthly wholesale natural gas prices at the Sumas trading hub. Prices peaked at $17/MMBtu relative to historical values around $2/MMBtu. Prices in Southern California spiked as high as $50/MMBtu during this period. It is interesting to note that wholesale natural gas prices on the West Coast did not rise dramatically until the peak heating season, when demand for heating combined with demand for natural gas generation pushed the natural gas supply and delivery system to the limit. By fall 2001 prices had returned to historical levels.

[11] The gas industry was producing at over 95 percent of capacity by 2000 versus about 85 percent of capacity in 1990.

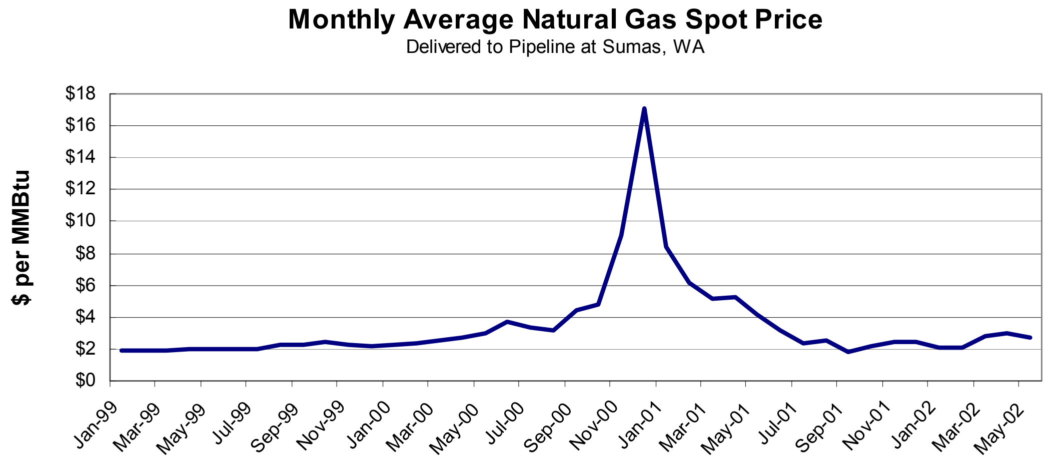

Figure 1.5. Wholesale Natural Gas Prices Source Nat. Gas Weekly

Higher wholesale natural gas prices translated into higher natural gas prices for consumers. In Washington State, gas utilities use Purchased Gas Adjustments (PGA) to pass through actual gas acquisition costs to retail customers with periodic rate adjustments, subject to Washington Utilities and Transportation Commission audit and review.[12] As a result, consumers saw the price they paid for natural gas increase relatively quickly (Figure 1.6). In 1998, the average residential price for natural gas was $5.84/Thousand cubic feet (Mcf),[13] but by Summer 2001 the price peaked above $11/Mcf before dropping a little below $10/Mcf. Similarly in the commercial sector, the price went from an average of $4.75/Mcf in 1998 to a little more than $9/Mcf by mid-2001. In 2001, the average residential consumer paid $360 more than in 1999 for natural gas and the average commercial consumer paid $2,330 more. Note that many industrial consumers do not purchase their natural gas from retail utilities, thus this information is not publicly available. The impact of higher wholesale natural gas prices on industrial customers largely depended on the nature of their contracts with natural gas suppliers.

[12] Each natural gas local distribution company makes a PGA filing each year, which establishes natural gas costs for the coming year. This process looks at past costs as well as future projections and makes adjustments as needed (Washington Administrative Code (WAC) 480-90-233). The PGA is intended to pass actual utility costs for acquiring natural gas to customers. Avista has a price benchmark mechanism in their natural gas tariff that provides an incentive to them if they beat the benchmark in their purchases of natural gas. Puget Sound Energy used a similar incentive mechanism that gave them the opportunity to earn a profit on the commodity portion of gas sales if they beat a price index, but use of this incentive has ended. Cascade Natural Gas and Northwest Natural Gas have never used an incentive mechanism.

[13] One thousand cubic feet (Mcf). One thousand and thirty cubic feet is equivalent to one million Btu, depending on the exact energy content of the natural gas. For practical purposes 1 Mcf = 1 MMBtu.

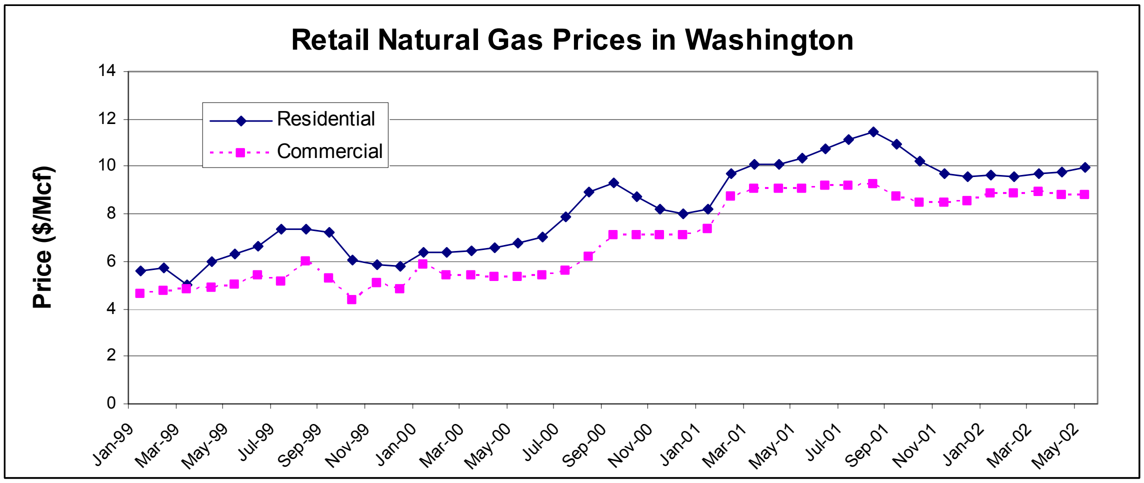

Figure 1.6. Natural Gas Prices during the Energy Crisis for Residential and Commercial Consumers Source EIA, BEA

In California, there were a small number of rolling blackouts in the winter and spring of 2001 due to insufficient electricity supplies. A significant number of blackouts were expected in summer 2001, but these were avoided largely due to an unprecedented degree of conservation and demand reductions from consumers in both California and the Pacific Northwest and the addition of temporary and permanent generating capacity. This included the shutdown of aluminum smelters in the Pacific Northwest, which accounted for a sizable portion of the load reduction in the region. Even though supplies were tight, there were no reliability problems. A small number of customers paying market based rates for energy chose to discontinue service during this period due to high energy costs. There are a small number of utility customers with interruptible natural gas or electricity service. At times these customers can have their service shut down during peak periods under the terms of their interruptible contracts. This rarely occurs and if it does it is usually a result of constraints on a local utility system. Although there are no specific data available, we are not aware of any interruptions of service to these customers in Washington State due to the West Coast energy crisis.

Was the energy crisis of 2000 and 2001 an isolated event? Will the pre-crisis situation of adequate energy supplies and stable prices return? The events of 2000 and 2001 clearly illustrated:

- The convergence of natural gas and electricity energy markets. The growing demand for natural gas for electricity generation ensures that this will continue.
- Pacific Northwest natural gas markets are not isolated, but are influenced by events on the West Coast and throughout the rest of the country.
- In 2001, the Pacific Northwest natural gas supply and delivery system was nearing its capacity and had limited ability to meet additional demand without expansion.

These lessons from 2000/2001 suggest that there is potential for continued volatility in natural gas markets in the Pacific Northwest.

Post Crisis Period

By late 2001, both wholesale electricity and natural gas prices had returned to historic levels. It appeared the crisis was over. More favorable weather, the effects of the recession, the aluminum smelters going off line in the Northwest, and better hydro conditions all reduced demand for natural gas. But this situation began to change towards the end of 2002 as the result of colder weather and low natural gas storage levels in the eastern United States. Spot market prices in the Pacific Northwest rose to $5/MMBtu by February 2003, spiked to $8/MMBtu in early March, and are remaining near the $5 level (Figure 1.7). Prices spiked even higher in other parts of the country, reflecting national market conditions.

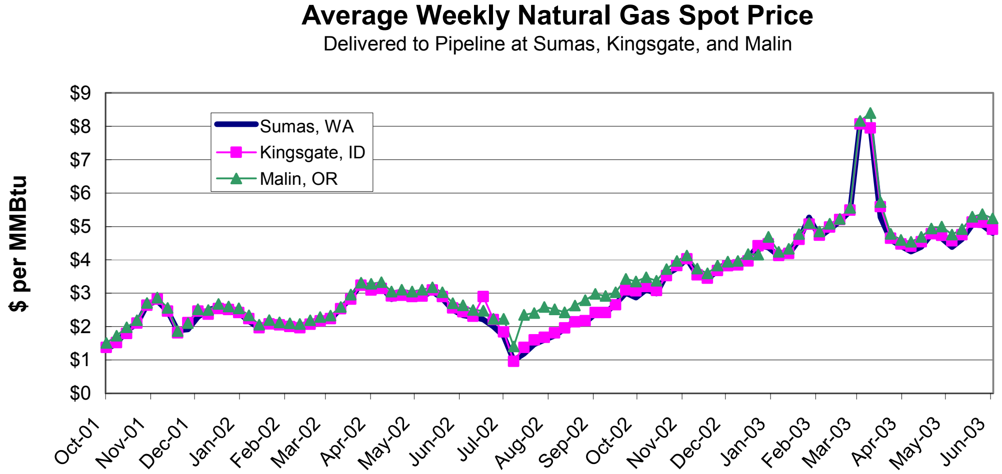

Figure 1.7. Recent Wholesale Natural Gas Prices in the Northwest
Source Nat. Gas Weekly

The near-term outlook for U.S. natural gas markets suggests there will be upward pressure on prices and there is potential for continued market volatility. Limited growth in natural gas supply combined with increased demand has resulted in a tight balance between supply and demand. Output from conventional sources for natural gas may not be able to meet growing demand, suggesting the need to develop more expensive non-conventional sources, such as coal-bed methane. Natural gas future prices were around $6/MMBtu through 2004, suggesting future prices might continue to be higher than historical values.

The use of natural gas for electricity generation has been driving the growth in demand for natural gas nationally. In 2000, plans called for the bulk of the Pacific Northwest region's growth in electricity demand to be met with natural gas-fired generating capacity; and at the time over 12,000 MW of natural gas-fired generation was in various stages of construction, permitting or planning in the region. Market conditions have changed and electricity demand and prices are down, making the situation less favorable for construction of some of these plants. But a significant amount of natural gas-fired generation capacity has recently come on line or is under construction.

Table 1.2 identifies the capacity of plants that have been recently constructed in the Pacific Northwest as well as those under construction and in different stages of planning. The capacity of plants that have come into service (on line in 2000 or later) plus those under construction is greater than the total existing capacity. But over 7,000 MW of new capacity, some of it under construction, has been deferred, suspended or terminated. And few of the plants that are permitted or planned are likely to be constructed given recent declines in electricity demand and little likelihood of returning to current levels of demand in the near term.

Table 1.2. New Natural Gas Power Plants in the Pacific Northwest Region

Status	Number	Capacity (MW)
Existing (pre-2000)	28	3180
Recently In-Service	27	2867
Under Construction	4	867
Permitted	11	5551
Permitting/Planned	13	6290
Potential	8	2633
Retired	5	282
Deferred	5	3001
Suspended	3	1176
Terminated	21	3047

Source: Northwest Power Planning Council, October 2003

In the remainder of the report, we examine key issues about uncertainty and price volatility in natural gas markets including growing demand, reduced demand responsiveness, supply uncertainty, and constrained infrastructure. In Section 2 we review natural gas reserves and resources. Section 3 examines natural gas production by region; Section 4 focuses on recent long-term natural gas supply, while Section 5 delves into recent demand forecasts. Section 6 gives a review of recent natural gas price trends and market forecasts, while Section 7 provides an overview of gas pipeline and storage capacity and the ability of this infrastructure to meet needs in the region. The report concludes with a summary of key findings (Section 8) and a presentation of policy issues (Section 9) at the national and regional level. Five appendices are included covering: a.) The possibility of peak natural gas production in North America, b.) Proposed LNG facilities in North America, c.) Price-demand dynamics in the natural gas market, d.) Utility energy efficiency programs, and e.) Financial tools for natural gas portfolio management